Coupling the Alkaline-Surfactant-Polymer Technology and The Gelation Technology to Maximize Oil Production

Topical Report
Translation of Laboratory Data to Field Alkaline-Surfactant-Polymer Projects

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Abstract

Performance and produced polymer evaluation of four alkaline-surfactant-polymer projects concluded that only one of the projects could have benefited from combining the alkaline-surfactant-polymer and gelation technologies. Cambridge, the 1993 Daqing, Mellott Ranch, and the Wardlaw alkaline-surfacant-polymer floods were studied. An initial gel treatment followed by an alkaline-surfactant-polymer flood in the Wardlaw field would have been a benefit due to reduction of fracture flow.

Numerical simulation demonstrated that reducing the permeability of a high permeability zone of a reservoir with gel improved both waterflood and alkaline-surfactant-polymer flood oil recovery. A Minnelusa reservoir with both A and B sand production was simulated. A and B sands are separated by a shale layer. A sand and B sand waterflood oil recovery was improved by 196,000 bbls or 3.3% OOIP when a gel was placed in the B sand. Alkaline-surfactant-polymer flood oil recovery improvement over a waterflood was 392,000 bbls or 6.5% OOIP. Placing a gel into the B sand prior to an alkaline-surfactant-polymer flood resulted in 989,000 bbl or 16.4 % OOIP more oil than only water injection. A sand and B sand alkaline-surfactant-polymer flood oil recovery was improved by 596,000 bbls or 9.9% OOIP when a gel was placed in the B sand.

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Introduction

Gelation technologies provide more efficient vertical sweep efficiencies for flooding naturally fractured oil reservoirs and divert injected fluid into lower permeability zones in reservoirs with high permeability contrast zones. Field proven alkaline-surfactant-polymer technology economically recovers 15% to 25% OOIP more oil than waterflooding from swept pore space of an oil reservoir. However, alkaline-surfactant-polymer technology is not amenable to naturally fractured reservoirs or those with high permeability contrast zones because much of the injected solution bypasses target pore space containing oil. This work investigates whether combining these two technologies could broaden applicability of alkaline-surfactant-polymer flooding.

Executive Summary

Evaluation of different alkaline-surfactant-polymer floods at the Cambridge, 1993 Daqing, Mellott Ranch, and Wardlaw floods indicates that in the Wardlaw field coupling the alkaline-surfactant-polymer technology and the gelation technology could have made the difference between stopping future application of the alkaline-surfactant-polymer technology due to fractures. Oil recovery performance of the first three projects suggests that combining the two technologies would have had limited improvement of oil recovery over the alkaline-surfactant-polymer technology alone.

Numerical simulation of applying a gel treatment to a Minnelusa reservoir with two sands separated by shale indicates that prior treatment of the higher permeability sand with gel will recover additional oil. Waterflood oil recovery is improved by 196,000 bbls with gel treatment. Alkaline-surfactant-polymer flood oil recovery is improved by 596,000 bbls with prior gel injection. Total oil recovery improvement of combining an alkaline-surfactant-polymer flood with a gel treatment was 989,090 over the base waterflood.

Evaluation of Alkaline-Surfactant-Polymer Floods' Field Performance and Potential Benefit of Combining Alkaline-Surfactant-Polymer and Gelation Technologies

Break through of polymer at alkaline-surfactant-polymer floods in the Cambridge, 1993 Daqing, Mellott Ranch, and Wardlaw fields were compared with the appearance of polymer production in respective radial corefloods. Inherent in the comparison is field and laboratory adsorption of polymer is the same. Because reservoir core, oil, and water were used in all laboratory evaluations and the same chemicals were injected, the chance of a significant difference in adsorption characteristics are lessened. Another inherent assumption is the oil saturation after the injection of alkaline-surfactant-polymer solution is similar in the field and the laboratory. Polymer breakthrough in field applications and laboratory radial corefloods are compared in Table 1.

Table 1
Polymer Break Through in Alkaline-Surfactant-Polymer Field and Radial Corefloods

Field	Initial Polymer Production Pore Volume After Beginning ASP Injection Field	Coreflood
Cambridge[1]		
Well 31-28	0.131	0.536
Well 21-28	>0.466 (end of field effluent testing)	0.536
Daqing 1993[2]		
Po5 Well (surrounded by 4 injector wells)	0.174	0.310
Mellott Ranch	0.155	0.198
Wardlaw	immediate	----

Initial analysis of the data in Table 34 suggests that the Cambridge, Daqing 1993, and Wardlaw projects might have benefited from applying a gel treatment. However, polymer production is only one part of the analyses. Oil recovery performance must be factored into the equation.

- **Cambridge Field Alkaline-Surfactant-Polymer Flood** – The different wells polymer production suggest that a gel treatment might have benefited one well but not the second. Oil recovery in the field of 73% OOIP with 34% OOIP incremental oil indicates that the reservoir was swept and oil recovery was good in spite of early polymer break through at one well. Data indicates generally good contact efficiency of the injected solution in the field application. Coupling the alkaline-surfactant-polymer technology with a gelation technology would not have been of significant benefit.
- **Daqing 1993 Alkaline-Surfactant-Polymer Flood** – Divergence between polymer appearance in the Daqing field and laboratory alkaline-surfactant-polymer floods is not as great as the Cambridge Field application. Data indicates that coupling the alkaline-surfactant-polymer flood technology with gelation technology might have improved oil recovery. Gao et.al.[2] reported 19% OOIP incremental oil recovery in the 1993 project and Wang et.al.[3] reported up to between 20 and 26% OOIP incremental oil recovery in five ASP pilot projects. Laboratory alkaline-surfactant-polymer incremental oil recovery ranged from 19 to 28% OOIP with similar alkaline-surfactant-polymer solutions. Data suggests that coupling the alkaline-surfactant-polymer technology with a gelation technology benefit would have been low, 0 to 5 % OOIP.
- **Mellott Ranch Alkaline-Surfactant-Polymer Flood** – Laboratory and field initial polymer production suggest the field is performing similar to the corefloods. Oil recovery performance is premature since the flood is on-going. Data indicates that injection of a gel into the Mellott field is not warranted.
- **Wardlaw Alkaline-Surfactant-Polymer Flood** - Immediate break through of polymer with injection of an alkaline-surfactant-polymer solution indicated that injected fluid was not flowing through matrix containing oil. Immediate break

through was attributed to fracture flow, ideal for improvement with a gelation technology. If a chromium acetate-polyacrylamide gel treatment had been performed, an alkaline-surfactant-polymer flood might have been feasible. The difference in oil recovery would have been from 0% OOIP due to the failure of the injected solution to contact the rock matrix to as high as 30% OOIP as produced from the Cambridge projected and the Wardlaw radial corefloods.

Numerical Simulation of a Crosslink-Alkaline-Surfactant-Polymer Flood

The Wardlaw field with its fracture flow represents one ideal situation to which the alkaline-surfactant-polymer technology can be coupled with a gelation technology to produce significant volumes of incremental oil. The second ideal situation is when two alkaline-surfactant-polymer sensitive sand lenses are separated by a no-flow barrier with injection and production wells open to both zones. A Minnelusa reservoir with an "A" sand and a "B" sand with common production and injection wells was simulated to demonstrate improvement of oil recovery after gel treatment followed by an alkaline-surfactant-polymer flood in a reservoir with two sand lenses. A and B sands are separated by a shale layer. GCOMP numerical simulation software was used.[4] GCOMP is a black oil numerical simulation package with a chemical flood option.

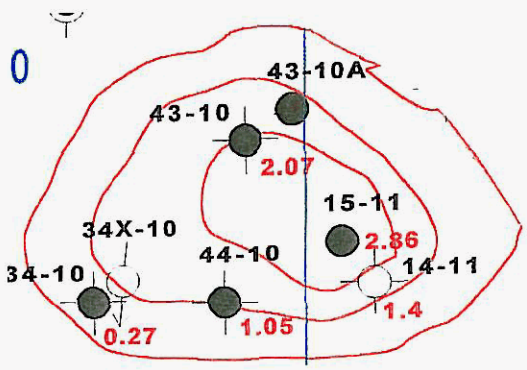

Figure 1 Minnelusa Field Well Orientation

The flood consists of one injection well (34X-10) and two production wells (43-10A and 15-11). Wells 44-10, 14-11, 43-10, and 34-10 were either dry holes or were lost prior to contemplating alkaline-surfactant-polymer injection. Figure 1 depicts the well orientation.

Reservoir and Model Definition

A 20 by 14 grid model consisting of seven layers with the top two layers A sand and bottom five layers presenting the B sand was defined. Table 2 lists individual layer parameters.

Table 2
Numerical Simulation Layer Parameters

	Layer	Pay (ft)		Porosity (%)	KXY (md)	KZ (md)	Pore Volume (bbls)
A Sand	1	4.3		20.2	224	184	1,286,600
	2	10.5		19.9	381	312	3,136,523
	Sum	14.8	Average	20.0	302	248	4,423,123
B Sand	4	1.3		21.0	506	415	18,469
	5	0.5		18.5	79	65	4,995
	6	9.4		17.7	807	662	2,259,435
	7	6.5		12.1	565	463	909,069
	Sum	17.7	Average	17.3	626	512	3,191,968

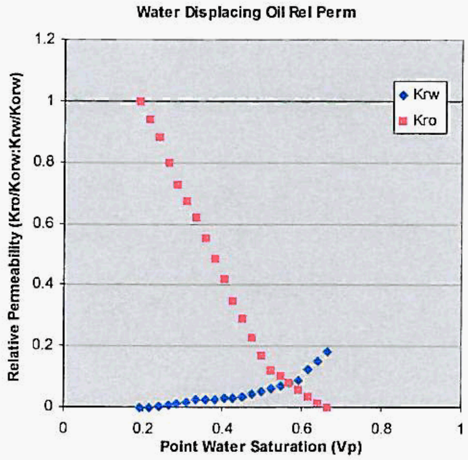

Figure 2 Minnelusa Oil-Water Relative Permeability Curve

Initial oil saturation was 0.805 V_p and water flood residual oil saturation was 0.335 V_p. Figure 2 depicts the water displacing oil relative permeability curve. Initial reservoir pressure was 2685 psi. Reservoir temperature was 133°F. The Minnelusa Field produces a dead crude oil with an API gravity of 21.5° and a viscosity of 29 cp at initial reservoir pressure and temperature. Formation volume factor was 1.02. Bubble point was 175 psi. Fluid and rock compressibilities used in the model are water 2.95E-06 psi^{-1}, crude oil 5.79E-06 psi^{-1}, and rock 2.7E-05 psi^{-1}. Transmissivity between the layers was equal to 82% of the horizontal transmissivity.

History Match - Model Validation

A production waterflood history match was performed by fixing the oil rate from each well and allowing water rate and oil cut to vary according to relative permeability characteristics and model saturation conditions. History match was from 1961 to 2003. Figure 3 shows oil rate, water rate, and oil cut match for the wells. Injection matched historical values exactly.

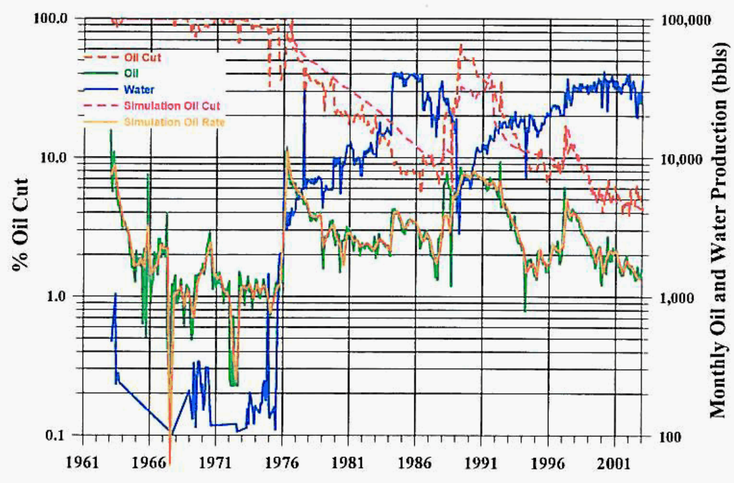

Figure 3 History Match –Primary/Waterflood Production

Coreflood History Match - Chemical Model Validation

An alkaline-surfactant-polymer radial coreflood was history matched to calibrate model chemical option. Coreflood used reservoir crude oil, produced water, and reservoir core. Chemical system used was 1.00 wt% NaOH plus 0.1 wt% ORS-46HF plus 1300 mg/L Alcoflood 1275A. Linear coreflood data was used to develop adsorption isotherms and polymer rheology data. Interfacial tension values used in the model are from laboratory measurements.

Radial coreflood model consisted of a 5 by 1 radial grid system with 2 layers. Initial oil saturation was 0.805 V_p. Initial reservoir pressure was 2685 psi. PVT characteristics were such that the viscosity of the crude oil was 28 cp at 133° F at 2685 psi. No water-oil or gas-oil contacts were present. PVT characteristics and relative permeability curves from the field history match were used in the coreflood match.

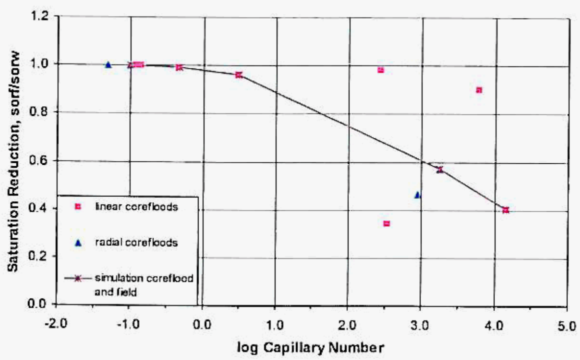

Figure 4 Oil Saturation Reduction versus log Capillary Number

Coreflood history match was achieved by changing permeability and capillary number de-saturation curve. Final permeability distribution was 14 md for both layers. This compares to 13.6 and 16.3 md for the effective permeability to oil and effective permeability to water, respectively. Figure 4 shows the capillary de-saturation curve required to match the coreflood. Note, the capillary number - de-saturation correlation matched coreflood values during waterflood. As capillary number increased due to chemical injection, linear coreflood data facilitated a match better than radial coreflood data.

Figures 5 and 6 show oil recovery and oil cut history match, and produced chemical match for

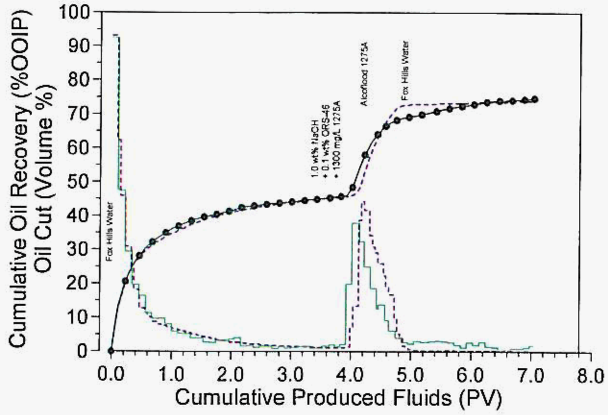

Figure 5 Oil Cut and Cumulative Oil Recovery Radial Coreflood History Match

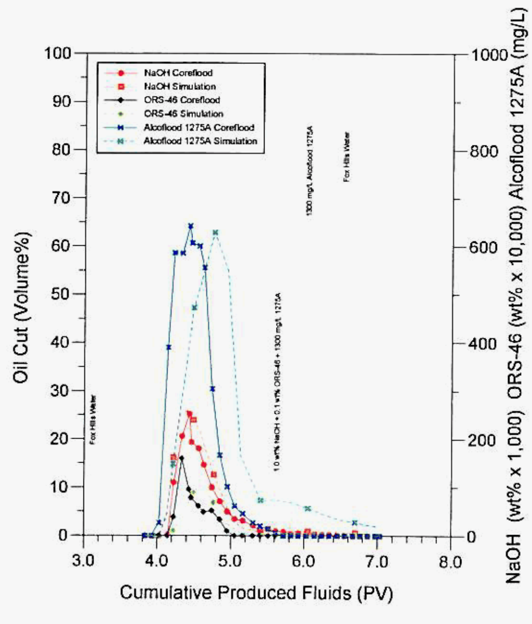

Figure 6 Produced Chemical Radial Coreflood History Match

the alkaline-surfactant-polymer radial coreflood. Both the waterflood and chemical flood oil recoveries are duplicated by the numerical simulation indicating the relative permeability and capillary number calculation accurately depict the waterflood and the alkaline-surfactant-polymer flood for the Minnelusa oil, water, and rock system. Produced chemicals were similarly matched.

Alkaline-Polymer and Alkaline-Surfactant-Polymer Forecasts

Five forecasts were made:

1. Waterflood through 2020
2. Crosslink B Sand in 2003 followed by water through 2020
3. No Crosslink, ASP Flood:
   B Sand - 0.262 V_p ASP followed by 0.278 V_p polymer drive followed by water to 2020 (0.972 V_p)
   A Sand - 0.024 V_p ASP followed by 0.076 V_p polymer drive followed by water to 2020 (0.049 V_p)
4. Crosslink B Sand and inject chemical over the same time as case 3:
   B Sand - 0.091 V_p ASP followed by 0.110 V_p polymer drive followed by water to 2020 (0.885 V_p)
   A Sand - 0.036 V_p ASP followed by 0.098 V_p polymer drive followed by water to 2020 (0.087 V_p)
5. Crosslink B Sand and inject chemical until approximately 0.25 Vp of ASP solution has been injected into the B Sand:
   B Sand - 0.239 V_p ASP followed by 0.152 V_p polymer drive followed by water to 2020 (0.315 V_p)
   A Sand - 0.124 V_p ASP followed by 0.126 V_p polymer drive followed by water

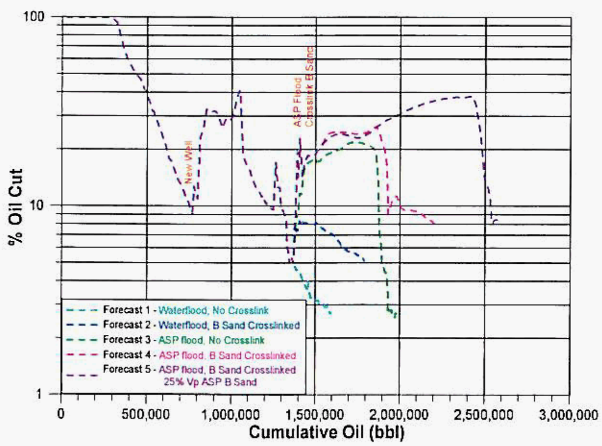

Figure 7 Oil Cut versus Cumulative Oil Produced for the Five Forecast Cases

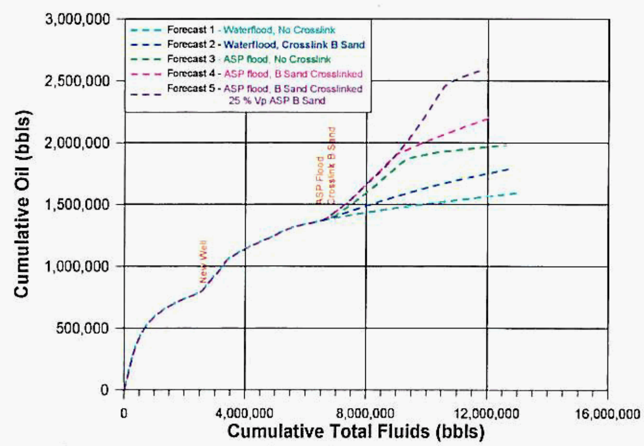

Figure 8 Cumulative Oil Produced versus Cumulative Total Fluids for the Five Forecast Cases

to 2020 (0.027 V_p)

Figure 7 depicts the oil cut as a function of cumulative oil production and Figure 8 depicts cumulative oil as function of cumulative total fluids produced. Crosslinking of the B Sand was simulated by injecting 1500 mg/L mobility control polymer solution into the B Sand for 2 days.

At two days, injection was stopped and the concentration of polymer in the grid blocks surrounding the injection well determined. In a separate run file, gel placement was simulated by decreasing the X, Y, and Z transmissivity of the B Sand to 20% of the original value if the concentration of polymer in the grid block was equal to the injected concentration. If the concentration of polymer was less than injected concentration, transmissivity decrease was adjusted by multiplying by the dividend of grid concentration divided by injected concentration. A 20% decrease of transmisivity corresponds to a resistance factor of 5. Transmissivity instead of resistance factor was altered due to limitation of the numerical simulator with subsequent injection of a mobility control fluid, which itself has a residual resistance factor. The numerical simulator does not distinguish between gel polymer and mobility control polymer residual resistance factor.

Note in Figure 7 the volume of fluids produced and, therefore, injected decreases when either the B Sand is crosslinked or viscous ASP solution is injected. Total fluid produced volume and, therefore, injection volume decreased by up to 2,800,000 bbls. Table 3 summarizes incremental oil produced.

Table 3

Waterflood and Alkaline-Surfactant-Polymer Flood Forecast Incremental Oil Production

		---------Incremental Oil Production (bbls) ---------	
Forecast	Description	Over Waterflood	Over no Crosslink ASP Flood
2	B Sand Crosslink Waterflood	196,144	-------
3	No Crosslink ASP Flood	392,656	-------
4	B Sand Crosslink ASP Flood	619,988	227,332
5	B Sand Crosslink 25% Vp ASP Flood	989,090	596,436

Conclusions

1. Aluminum-polyacrylamide gels, either at low polymer and aluminum concentration or at high polymer and aluminum concentration, were not stable to alkaline-surfactant-polymer solutions with pH values ranging from 9.2 to 12.9.
2. Aluminum citrate-polyacrylamide gels were not stable to subsequent injection of either a NaOH or a Na_2CO_3 alkaline-surfactant-polymer solution.
3. Chromium-polyacrylamide gels were stable to alkaline-surfactant-polymer solutions with pH values ranging from 9.2 to 12.9 when the polymer to chromium ion ratio was 15 or less. At polymer to chromium ion ratio of 25 or greater, chromium-polyacrylamide gels were not stable to alkaline-surfactant-polymer solutions with pH values of 12 or greater.
4. Chromium-polyacrylamide gels are stable to injection of either a NaOH or a Na_2CO_3 alkaline-surfactant-polymer solution. from 72°F to 175°F.
5. Flowing and rigid tonguing chromium-polyacrylamide gels were stable to injection of both NaOH and Na_2CO_3 alkaline-surfactant-polymer solutions. Rigid tonguing gels maintained permeability reduction after an alkaline-surfactant-polymer solution was injected while flowing gels permeability increased but not to either pre-gel or alkaline-surfactant-polymer flush values.
6. Chromium-xanthan gum gels were stable to alkaline-surfactant-polymer solutions with pH values ranging from 9.2 to 12.9 at the polymer to chromium ion concentration ratios tested.
7. Chromium-xanthan gum gels are not stable to injection of either a NaOH or a Na_2CO_3 alkaline-surfactant-polymer solution.
8. Silicate-polyacrylamide gels were stable to alkaline-surfactant-polymer solutions with pH values ranging from 9.2 to 12.9.
9. Silicate-polyacrylamide gels were not stable to subsequent injection of either a NaOH or a Na_2CO_3 alkaline-surfactant-polymer solution.
10. Resorcinol-formaldehyde and sulfomethylated resorcinol-formaldehyde gels were stable to alkaline-surfactant-polymer solutions with pH values ranging from 9.2 to 12.9.
11. Iron-polyacrylamide gels were not stable to alkaline-surfactant-polymer solutions regardless of pH.
12. Prior gel sequence injection did not reduce the total oil recovered by a waterflood plus alkaline-surfactant-polymer solution with the exception of the resorcinol-formaldehyde gel.
13. Gel injection followed by alkaline-surfactant-polymer injection will improve oil recovery by diverting alkaline-surfactant-polymer solution into lower permeability rock.
14. Gels used to seal fractures are stable to subsequent alkaline-surfactant-polymer solution injection, if gels are stable to alkaline-surfactant-polymer solutions in other applications.
15. Numerical simulation indicates placement of a gel into a higher permeability section of a reservoir will improve waterflood recovery and alkaline-surfactant-polymer flood oil recovery compared to the same injection fluid without a prior gel treatment.

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